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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Subject: Docket No. 2008-0273
Feed-In Tariffs Investigation
Information Request Responses

Pursuant to the Order Approving the HECO Companies' Proposed Procedural Order, as Modified, filed on January 20, 2009, attached are Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Limited ("MECO") (collectively, the "HECO Companies") and the Division of Consumer Advocacy's ("Consumer Advocate") joint responses to the information requests prepared by the Commission's consultant, the National Regulatory Research Institute, dated March 16, 2009.

Sincerely,

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Attachments

cc: Service List

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(Docket No. 2008-0273)

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PUC-IR-A

Ref: Procurement techniques

According to Page 4 of the Department of Business, Economic Development, and Tourism's Opening Statement:

> "More importantly, the current bid process only applies to renewable resources with capacity of at least 5 MW (2.72 MW for MECO and HELCO), and there are no clear procurement rules required under the utility's current competitive bidding framework for the smaller renewable generators that are below this threshold size. Furthermore, the utility procurement of renewable generation that meets the capacity size thresholds without a utility-issued RFP will require a PUC-approved waiver from the competitive bidding framework, for which only the utility can apply or petition."

1. **Is this a reasonable assessment of HECO's procedures? If not, please explain why it is not.**
2. **What are the procurement rules and procedures for renewable energy projects that are not eligible for net metering but below 5 MW for HECO (and lower for MECO and HELCO)?**
3. **What was the total amount of capacity of renewables integrated into the HECO Companies' transmission system during 2006, 2007, and 2008 using each of the following: competitive bidding, negotiated power purchase agreements, and net metering? Please list such capacity additions for each island and for each renewable technology.**
4. **Please list all renewables projects that are planned or under construction in Hawaii and have been awarded contracts by the HECO Companies through either competitive or negotiated power purchase agreements. For each project, list if the project used competitive bidding or a negotiated power purchase agreement, the size in kW, the technology and the location**

Response:

1. DBEDT's statement is not a reasonable assessment of HECO's procedures. The Framework for Competitive Bidding, adopted by the Commission in Decision and Order No. 23121, issued December 8, 2006 in Docket No. 03-0372 ("Competitive Bidding Framework"), provides the basis for applicability to its Framework. For any resource to

which the Competitive Bidding Framework requirement does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and/or energy from a qualifying facility ("QF"), as referred to in the Hawaii Administrative Rules Chapter 6-74, at or below avoided cost upon reasonable terms and conditions approved by the Commission. QF's in Hawaii that have existing facilities also have existing PPA's, and the utilities' right and obligations with respect to those facilities are now governed by the PPA's (at least until the PPA's terminate).

Proposed facilities also may have rights under Public Utility Regulatory Policies Act of 1978, as amended ("PURPA") and applicable rules, if (1) they meet the QF requirements, (2) the proposed facilities are sufficiently advanced and viable, and (3) their offers to sell power to the utility is sufficiently comprehensive, binding and reasonable – that is, if the utility incurs a "legally enforceable obligation" to purchase the power at its avoided cost.

Further, the utility may have an obligation to negotiate with the developer of the proposed facility before it incurs a "legally enforceable obligation" to purchase the power, but the point at which the obligation to negotiate occurs is generally a matter of State administrative law or practice, and a State commission may defer or relieve a utility of the obligation to negotiate as a result of a competitive bidding process.

As a practical matter, a utility's "PURPA" obligation in such negotiations is to offer to purchase at avoided costs under reasonable terms and conditions.

2. See response to 1 above.

3. See chart below for requested information.

Year	Island	Competitive bidding[1] (kW)	Negotiated Power Purchase Agreements (kW)				Net Energy Metering (kW)			
			PV	Wind	Hydro	Total	PV	Wind	Hydro	Total
2006	Oahu	0				-	74			74
2006	Hawaii			10,560		10,560	298	2		300
2006	Maui			30,000	500	30,500	232			232
2006	Total		-	40,560	500	41,060	604	2		606
2007	Oahu	0				-	387			387
2007	Hawaii			7,000		7,000	263			263
2007	Maui					-	358			358
2007	Total		-	7,000	-	7,000	1,009			1,009
2008	Oahu	0				-	2,362	0.4		2,362
2008	Hawaii				50	50	713	20	49	782
2008	Maui				1,200	1,200	949	3.6		953
2008	Total		-	0	1,250	1,250	4,024	24	49	4,097

4. Renewable projects that are planned or under construction and have been awarded contracts by the HECO companies include: (i) 218kW Archer Sub Photovoltaic project on Oahu; (ii) 500kW Keahole Solar Power Concentrating Solar Power project on Hawaii; and (iii) a biomass-fired cogeneration project on the Big Island, for which a PPA was executed (subject to amendment based on the now completed IRS), but which is still obtaining financing for the project. Of these two projects, Archer Sub PV was awarded a contract through a competitive procurement process, Keahole Solar Power was awarded a

[1] The HECO renewable energy RFP anticipates submitting PPAs to the Commission for approval of approximately 100 MW of renewable energy projects by the end of 2009.

contract through a negotiated power purchase agreement, and the Tradewinds cogeneration project secured a contract through a process grandfathered from the Competitive Bidding Framework.

PUC-IR-B

Ref: Rule 14

According to Page 5 of the Solar Alliance's Opening Statement:
"Specifically, SA has concerns about Rule 14, Appendix 1, Section 2. General Interconnection Guidelines d. Utility Feeder Penetration. This section has a ten percent feeder penetration which is inconsistent with the Hawaii Clean Energy Agreement. SA proposes that the language in this section of Rule 14 be modified to incorporate the 15%, 12 kVa circuit level prior to any study being required. Also, the information provided by the "Location Value Maps"

1. Please describe the basis for the current 10% feeder penetration restriction.
2. What might the reliability consequences be of increasing the feeder penetration limit to 15% for Rule 14, Appendix 1, Section 2?

According to Page 5 of the Solar Alliance's Opening Statement:

"SA also has concerns about Rule 14, Section 3 Design Requirements, f. Supervisory control. This section states that the utility can require computerized remote control for any generating facilities with an aggregate capacity of more than 1 MW. This requirement creates a "system size benchmark" which third party investors may not want to exceed, fearing additional costs, studies, remote curtailment. Thus they would only put in systems up to 1MW even if they could use 1.5MW to offset the customer load."

3. Please describe the basis for the current remote control requirement for systems of more than 1 MW.
4. What might the reliability consequences be of removing the remote control stipulation of Rule 14, Section 3 Design Requirements, f. Supervisory control?

Response:

1. The 10% of maximum load threshold is not a limit on penetration, but rather is a trigger used to identify the point at which a study would be prudent to evaluate the potential impacts of a new resource on the distribution system and, consequently, the loads served by that distribution system. The 10% threshold provides a reasonable estimate suggesting the generator, or aggregate distributed generation, is most likely insignificant enough relative to the size of the feeder and

native feeder load to prevent problems so long as standard interconnection requirements are employed. However, this rule-of-thumb does not completely rule-out potential issues such as boundary conditions which can occur with maximum generation at minimum load, and also depends upon the type of proposed generation, its location along the feeder, and its size. The general guideline for a "reasonable safe" level not requiring analysis for distributed generation on circuit is the minimum load on the circuit at approximately 3 times the generation. It is generally a matter of engineering judgment whether this level is sufficient or if higher or lower levels would be more appropriate. Although it is understood that the minimum loading is an important boundary condition, especially as pertains to the potential for islanding, distribution engineers typically only have data recorded for the circuit peak and the average load based on the MWH meter, rather than the minimum. To estimate the minimum load on the circuit, a typical load factor curve is used to translate the percent of circuit minimum to a percent of circuit peak. The engineers then base their analysis on this estimate. A 10% penetration of load would generally correspond to a safe size relative to minimum load on a circuit assuming a 75% load factor. However, if the load factor varies from the norm, or if conditions change on the circuit, the methodology could fail to capture a condition where the generator is actually large enough to justify further analysis.

Additionally, The larger the generator, and further from the substation, the more likely that constraints will be encountered due to feeder loading or voltage impacts. The potential to form electrical islands is another important consideration, the risk of which is reduced if the generator is small relative to the load on the distribution circuit.

The purpose of a distribution study is to evaluate the impact of the proposed generation on the distribution system through modeling. There are various modeling aspects:

a) Load-flow analysis which computes currents, voltages, real and reactive flows to detect any imbalances created in the system and to ensure that the voltages and currents under peak and minimum loading conditions comply with regulations imposed to maintain industry standards.

b) Short circuit analysis to ensure that fault levels produced by faults do not result in damage to utility or customer equipment or endanger life. In addition, the fault currents and voltages must be known for the proper application of protection coordination. The results of the analysis are used for comparison with plant fault current withstand levels for all post-fault periods defined as sub-transient, transient and steady state.

c) Harmonic analysis may be needed to ensure that current distortion at resonate frequencies are within acceptable limits and will not cause over voltages on the system. Power electronic converters, such as the inverters used for PV generation, can inject harmonic currents that can excite a circuit at resonant frequencies.

d) Voltage regulation analysis to determine the voltage regulation mode that should be used by the generator(s) on a circuit. Utilities typically use Load Tap Changers (LTCs) on their transformers feeding a circuit to regulate (adjust) the voltage on a circuit so that it remains within acceptable limits, taking into account the voltage drop on longer circuits. Introducing a significant amount of generation on a circuit will change the voltage drop assumptions on that circuit and the change will need to be coordinated with the LTC. If the LTC is not able to provide acceptable voltage regulation with the new generation online, the generator may need to help regulate the circuit voltage; this will also need to be coordinated with the LTC settings.

f) Flicker analysis may be needed to ensure that rapid changes in generator output will not cause objectionable voltage fluctuations for customers on that circuit.

The analysis performed varies by type of generator. For synchronous generation, loading cases to consider, particularly for impact on the voltage profile, would include:

- Full generation and peak distribution feeder load
- Full generation and minimum distribution feeder load
- No generation and peak feeder loading
- No generation and minimum feeder loading.

As mentioned above, the location of the generator is also important; the further the distance from the substation, the less likely that feeder loading considerations impose constraints on the possible size of the generator.

Induction generators, which are often used instead of synchronous generators especially for renewable energy projects, present different concerns. The main concern when connecting a conventional induction generator to a feeder is the reactive power demand of the generator, all of which has to be supplied through the feeder if no capacitive compensation is applied. This may require some compensation at the generator. Double-fed induction motors provide some capability to regulate voltage.

Regardless of type, the distributed generator may be connected to the power system through a step-up transformer. The design of this transformer will require the possible loading conditions on the feeder to determine the range of taps required to accommodate the voltage ranges for different reactive power flows. Failure to do so may prevent the machine from delivering the required reactive power due to tap limitations. The configuration (wye-wye, wye-delta, or delta-delta) of the transformer is also an important consideration in the analysis of transient voltages and protection systems.

The presence of distributed generation requires that several different types of analysis be used to ensure that disturbances or the switching of loads and generation do not result in unacceptable situations that lead to abnormal currents and voltages which violate standards for operation.

For generators above a certain size, or if a significant aggregate amount of distributed generation is expected on the power system, the settings for ride-through of off-normal voltages and frequencies will need to be reviewed to ensure that nuisance trips resulting from transmission system faults or events do not result in system problems. Expanded ride-through capabilities above the minimum IEEE 1547 settings provide better support for the power system as a whole but may require more sophisticated anti-islanding schemes to prevent unintentional islanding with the native distribution load, which could result in a live island operating outside of the standards for operation.

2. The potential impact of increasing the trigger for analysis from 10% to 15%, would be possible failure to perform analysis necessary to determine a significant impact of the distributed generator on feeder loading, islanding, short-circuit current, voltages, etc. as described under item (1). As described above, the rule-of-thumb establishing 10% as a trigger is in itself utilizing some approximation and judgment. Some utilities also use a size threshold, such as 300kW on

three-phase and 25 kW on single-phase, as a trigger study, in addition to simply using a relative size in percentage to maximum load as the trigger. A higher level trigger creates risk of failing to identify problems that would have been identified by such a distribution study and incorporate the required mitigating solutions into the interconnection design and system settings. The possible impacts could include: operation of the distribution circuit at currents, voltages or frequencies outside of acceptable limits and consequently damaging equipment (utility equipment, generator related equipment and other customer equipment on the distribution feeders) or causing customer complaints; miscoordination or failure of system protection to work correctly which could result in unnecessary outages or outages of longer duration, and/or equipment damage and safety hazards.

3. Supervisory control and monitoring allows visibility and control of the generator by the system operator. The threshold at which this is necessary is dependent upon the relative size of the generator compared with the power system to which it connects. Visibility allows the system operator to know that the generation is being produced and can monitor its variability, and can factor the output of that generator into dispatch decisions i.e.; starting additional generation, carrying more or less reserve depending on the observed nature of the generator, recording system data to determine the actual demand vs. apparent demand (load minus distributed generation), etc. Visibility and control can also allow the system operator to limit or remove the output of the generator under system conditions such as restoration from outages, excess energy conditions, or during line constraints. . For the HELCO system, previous guidelines required supervisory control for generators of 250 kW or larger. The size was increased relatively recently to 1 MW in an attempt to standardize the requirements for HECO, MECO and HELCO.

A typical minimum load for the HELCO system is 86 MW, day peak of 155-165 MW, and evening peak usually 20 MW more than day peak. It can be seen that it does not take very many 1-MW generators to have a significant impact on the load served by other generators for a system of HELCO's size. HELCO has four utility-owned diesels used for emergency balancing that are fully monitored and controlled that are 1 MW in size, one of 2 MW, and nine of 2.5 MW. The SOPOGY project, which is expected to connect this year, is sized at 400 kW, and its interconnection agreement requires supervisory monitoring and control. We have full monitoring and control of a utility-owned 300 kW hydro and two 750 kW hydro units. HELCO monitors the connection status of two customer-sited emergency generators for safety coordination purposes. HELCO system operations would advise that the size threshold for the Rule 14H supervisory control be returned to the previous threshold of 250 kW as more reasonable due to the impacts on the HELCO system, and because of the large number of existing and anticipated distributed generators on the system.

4. The consequence of allowing generators larger than 1 MW to connect without supervisory control and monitoring is that the system operator, who is responsible for generation dispatch for balancing and keeping the observed transmission and distribution system within operating parameters, will not be able to see the output of the generator and will not be able to control the output of the generator. The system operator will not be able to reduce the output of the generator even if it is contributing to system problems such as excess energy (high frequency), voltage problems, or overloads. The system operator would not be able to monitor or control the output of the generators during system restorations from outages. Uncoordinated reconnection of distributed generators during system restoration adds to the operator's challenges

trying to balance the connected system load and generation during restoration procedures. The system operator will not be able to verify that a generator is disconnected for safety reasons to ensure there is not the possible back feed onto a de-energized circuit prior to maintenance or emergency repair work. HELCO System Operators have seen greater variability in day time loads, with more uncertainty in the load forecast, in the past 12 months. There have been numerous PV installations on the distribution systems, but without a means to monitor the outputs in real-time, it can not be established empirically if the increase in distributed PV generation is the primary cause of increased load variability. It is correspondingly difficult to establish a pattern for forecasting the influence of distributed PV on the expected load based on temperature, weather, or other factors.

PUC-IR-C

Ref: Interconnection process

According to Page 6 of the HECO Companis and the Consumer Advocate's FiT proposal:

> "For example, larger, 'central station' generating resources must go through a complex interconnection requirements study ("IRS"). Even 'distributed generation' resources interconnecting into distribution circuits may trigger the need for more extensive studies and interconnection requirements."

1. Please describe the additional components of the IRS compared to the process used for smaller generators.
2. How much longer does the IRS process take than the process used for smaller generators?
3. What size or types of projects typically go through the IRS process? Please describe any capacity cut-offs used to determine when this method is applied.
4. Does HECO's current queuing and interconnection process allow the "fast-tracking" of smaller systems or must they wait for the interconnection studies of large systems to be completed? If not, please explain why such a system would or would not be possible.

Response:

1. The process used to evaluate the impact of small distributed generation is focused on the impact of that generation on the radial distribution feeder. Since distributed generation is normally relatively small, the analysis is usually limited to the radial feeder up to the point of the feeder's connection to the transmission system (and may include the distribution step-down transformer) but does not extend beyond to the effect upon the power system as a whole, unless it is expected that the generation will surpass the circuit load and inject power into the higher system voltages.

A more comprehensive study is necessary for large generators (relative to the system size) and generators connected to the transmission system in order to assess the impact on the overall power system. The analysis of large generation on distribution circuits can be more challenging to the extent that distribution systems have tighter tolerances for variations in voltage and the added concern of the potential islanding of the generation with the customers on the circuit. Some wind turbine designs have the potential of producing unacceptably high voltage levels when islanded from the utility grid. If the load is significantly larger than the generation, as with the 3 to 1 load to generation ratio mentioned in PUC-IR-B, the load will help to draw down the voltage on the circuit and mitigate the potential overvoltage.

There are similar tools used for the system impact study as described in PUC-IR-B for the distribution system: steady-state and transient modeling using dynamics simulation tools and load flows in order to determine the effect of the proposed addition on the stability of the system through faults and contingencies, and to ensure that the infrastructure supports the maximum output of the facility while maintaining acceptable system currents and voltages. Using these modeling tools, the study will identify issues caused by the new generation that need to be mitigated and it will identify infrastructure enhancements to the system that are needed to accommodate the addition, as well as technical requirements of the generator that are required to support the system.

The analysis for renewable energy units that have conventional characteristics, such as biomass, geothermal, and for conventional fossil units, is simpler than newer variable generation technologies. For conventional type units, standard tools have been developed to represent these units and the MW rate of change of these units is known and can be controlled. Variable renewable energy sources create more complex issues for several reasons. One is that valid, generic, non-proprietary power flow and stability models are not presently available. This has been identified as an area of development necessary to ensure the long-term power system reliability by a NERC task force on integration of variable generation. (The IVGTF final report will be available very shortly on the NERC web site). This is particularly challenging for islanded grids, since in some cases models are developed for use on large interconnected grids assuming little deviation from the normal system frequency. Islanded utilities need to ensure that the models developed by the generator manufacturer or model application developer provide valid results during off-normal frequencies as well. Secondly, it can be difficult to determine the production assumptions to use in the analysis as they are dependent upon a variable energy source and can also be site-specific and the rate of change and variability may not be known in advance. Developing the modeling assumptions becomes even more complicated when more than one variable energy source may coincide on the same portion of the network since the permutations of possible output scenarios become additive. For example, the utility would need to determine what the rapid ramp events look like at each facility and the combination of the two facilities and how often those ramp events happen at the same time. Similarly, the ride-through capabilities of the equipment may differ from conventional generation. Finally, variable generation creates operational issues, such as increased balancing requirements on a fast time scale, for which standard analysis tools are not yet available (for example, modeling the second-*to-second variability of the power system and the supplement frequency control, to study the* effect on system balancing).

Finally, the addition of distributed generation, can significantly impact system operations and their aggregate impact must be considered in the power system planning studies of the overall system. Modeling of these resources presents similar challenges to the modeling of transmission-side resource in addition to the unique issues presented by distributed generation being dispersed and having limited amounts of real-time data available to refine models.

2. The quote from Page 6 of the HECO Companies and the Consumer Advocate's FiT proposal was intended to convey that an IRS is required for larger "central station" generation, but a similar study effort may be required for distributed generation resources depending on the resource type, size, and location. The time needed to evaluate large distributed generation may not be much shorter than "central station" generation connected to the transmission system. In some cases the distribution connected generation may be more complicated and require the need for more sophisticated and accurate models.

3. Generally, IRS studies have been conducted for generation projects that require a power purchase agreement (PPA) with the utility. This includes projects that are not covered by standard interconnection requirements such as those in Rule 14.

4. The interconnection requirements for smaller systems may be developed in advance of larger systems if it can be determined that those systems are small enough such that they will not impact the interconnection requirements of the larger systems. One of the impacts of allowing smaller systems to interconnect without setting a system threshold, is that large renewable generation projects in the tens or hundreds of MW range could take years to permit and complete. Given the finite amount of energy that the Hawaii utilities deliver on their systems, committing to a large aggregate amount of small distributed generation that is ahead of the large generation projects in the curtailment order or that are not visible nor able to be curtailed by the

system operator could increase the curtailment experienced by the larger projects and reduce the amount of available demand that would be served by the larger projects. The large renewable generation projects need some level of certainty as to the amount of energy they will be able to sell to the utility to be able to finance their projects, particularly in the current economic environment. However the large, renewable generation projects typically offer superior system benefits and lower costs than smaller projects.

PUC-IR-D

<u>Ref: HECO FiT consequences and administrative costs</u>

1. With respect to HECO's request for 10% of the value of FiT purchases to be placed in rate base, please quantify the debt-imputation challenge that purchasing power under an FiT versus other purchased power agreements creates.
2. Please list any instances where a public utility commission denied the recovery of a power purchase where the rate had been pre-established through a tariff or where the purchase had been pre-approved as just and reasonable by the regulator.

According to Page 31 of the KEMA attachment to the HECD Companies and Consumer Advocate's FiT Proposal:

"Administrative resource requirements. Deploying the FIT will require the HECO Companies to process FIT applications, conduct Rule 14.H interconnection reviews, and otherwise administer the tariff. The annual FIT quantity target will aid in managing these administrative resource requirements."

3. Please estimate the annual administrative cost to the HECO Companies for each of the cost components described above if their FiT Proposal is adopted.
4. If larger systems than those proposed in the HECO Companies' FiT proposal were eligible or cumulative annual caps were high, please describe how the administrative costs would change.

<u>Response:</u>

1. HECO assesses imputed debt based on the S&P method of estimating imputed debt. See Attachment 1. To the extent that the terms and conditions of the FiT agreement are the same as a purchase power agreement, the credit quality impacts would be the same. HECO's FiT proposal would be treated the same as other contracts with "all-in energy prices." For power purchase contracts that have pricing based on a single, "all-in price" (such as the wind PPAs), S&P applies a proxy peaking capacity rate to the capacity of the facility, adjusted for the estimated capacity factor (i.e. the expected output/output capacity). The NPV of the "all-in price" and the evergreen obligations is calculated. The discount rate is based on the utility's average cost of debt. S&P currently uses a 6% discount rate for HECO. A risk

factor is applied to the NPV of the obligation. S&P currently applies a 50% risk factor to HECO's purchase power agreements; however S&P further indicates that the risk factor for purchased power agreements that are recovered through a power cost adjustment mechanism is 25%. For example, a 20 MW as-available 20-year purchase power agreement for a facility with an estimated capacity factor of 20% and 25% risk factor would have imputed debt in year one of approximately $1.5 million. The estimated cost to rebalance the utility's capital structure as a result of the additional imputed debt would be approximately $100,000. A FiT program for 20-year agreements that resulted in 20 MW of as-available power with an estimated capacity factor of 20% and 25% risk factor would have the same imputed debt and same imputed debt rebalancing costs. Purchased power agreements which have more fixed obligations would result in capital lease obligations or higher imputed debt calculations which would have larger negative impact on the utility's credit quality.

2. HECO is not aware of any instance where a public utility commission denied the recovery of a power purchase expense where the rate had been pre-established through a tariff or where the purchase had been pre-approved as just and reasonable by the regulator.
3. Appropriate and reasonable cost estimates will be dependent upon the FIT program parameters ultimately approved by the Commission. However, utilizing 2008 Net Energy Metering (NEM) administrative costs as a baseline and adjusting those costs to include larger project sizes, it is possible to provide an illustrative stimulate of the annual administrative costs associated with the processing of FIT applications, interconnection reviews and other administrative costs in the range of $500,000.
4. Larger systems would likely have more complex interconnection and other requirements which could result in both a greater amount of administrative time to manage those

applications as well as a greater level of expenditure of resources such as the costs of outside engineering consultants hired to conduct an Interconnection Review Study for the larger project.

Higher cumulative annual caps could result in more projects applying for the FIT. The actual costs impacts that would be associated with higher limits cannot be calculated without knowing the size of the annual caps and number and type of projects submitting applications, but conceivably costs would increase in relation to the need to process a greater number of applications.

The McGraw-Hill Companies

STANDARD
&POOR'S

Ratings

Standard & Poor?s Methodology For Imputing Debt For U.S. Utilities? Power Purchase Agreements

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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• Current Ratings

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

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Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of *mechanism as generally supportive of credit quality, the fact remains that the utility will need to* litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

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Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						

Debt to capitalization (%)	55.0
Ratios adjusted for debt imputation	
FFO to interest (x)§	4.0
FFO to total debt (%)**	18.0
Debt to capitalization (%)¶¶	59.0

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied deprecation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

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Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

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Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

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Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity. We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

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Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

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PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

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Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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PUC-IR-E

Ref: Other

1. On page 10 of the HECO Companies and the Consumer Advocate's Joint Proposal, the HECO Companies supported the use of annual FiT targets. Should these targets be calculated for each technology or island, or be based on other factors?
2. Should renewable energy annual aggregate caps or caps for the size of individual projects apply to renewable energy technologies that provide system benefits?
3. What would be the reliability impact of the FiT featuring higher system size eligibility limitations for generators that provide system reliability benefits, such as hydro and biomass generators? Please describe any compelling reliability and system integration reasons why non-intermittent renewable energy systems should not feature higher eligibility caps than intermittent systems.
4. Do the HECO Companies support paying FiT rates for the renewable energy production component of hybrid facilities that use a combination of renewable energy and fossil fuel? Please explain why or why not.
5. Are renewable generators currently compensated in any manner for curtailments? If so, please describe any compensation mechanisms.
6. Do the HECO Companies support the ability of utility affiliates to apply for FiT treatment? Restated, should any projects owned by HECO or its affiliates be eligible for the FiT? If they should be eligible, please explain how any conflicts of interests or unfair treatment of utility affiliate projects could be avoided.

Response:

1. The targets should be calculated for each technology and island. Annual FIT quantity targets will be established for each technology for each island and will be regularly updated in the course of the FIT Update.

2. The FIT applies to projects of a certain size and for each described type of technology there would be an annual target. The maximum project size was selected in order to facilitate standardized pricing, terms and conditions and interconnection requirements which would not be

available for larger projects due to the complexities that would be associated with the interconnection and integration of larger resources onto the Hawaii island grids. The setting of system-level targets would consider various factors as described in the response to PUC-IR-6. From the perspective of technical constraints only (that is, not considering implications on existing or potential energy projects) generators with less favorable grid characteristics ultimately require a lower system target than generators with more favorable grid characteristics, in order to preserve system reliability.

3. The reasons for selecting the individual project size are as described in the response to (2) above, and a system target for such resources would incorporate consideration of the system impact of such resources in determining the system level targets. Larger size projects would require more extensive interconnection analysis to determine the infrastructure impact, and will typically require supervisory control and monitoring. . Projects with conventional unit characteristics, such as biomass, geothermal and hydro projects, can provide significant benefits and ultimately lend themselves to higher levels of renewable energy penetration. To realize the full benefits possible from technology types like biomass or geothermal, and hydro with pondage, full dispatch capability with defined generator response characteristics would be necessary as well as terms guaranteeing capacity and availability. Often such projects benefit from economies of scale. Each island system could only accommodate a limited number of larger size projects and, in most cases, the possible siting would be restricted based on available resources and infrastructure (including transportation infrastructure in the case of biomass). The detailed study for technical and operational requirements for such project additions, which would be singular or few in number, and have significant impacts on the overall system operation and

performance, does not lend itself to standardized rates and interconnection requirements. The time required for interconnection analyses would not be shortened. A competitive bid process provides a superior means to procure this type of resource as a means to evaluate various proposals on the merits of cost and technical content.

4. At this time, hybrids are not being considered in the list of eligible technologies for the initial FIT. However, if there are projects that use this technology, they will be considered in future FIT updates.

5. As-available renewable generators are not currently compensated for curtailment. The HECO Companies compensate intermittent renewable generators for energy delivered to the point of interconnection on a per kWh basis and do not pay on a per kWh basis for energy which has not been delivered to the point of interconnection. Normal Dispatch of firm capacity renewable generators is specified in their contracts, i.e. these contracts specify minimum operating levels. Generally, the HECO Companies would not pay for energy from firm capacity renewable generators not dispatched in accordance with their contracts. Certain firm capacity renewable energy contracts specify a minimum kilowatthour purchase obligation by the utility such that the utility must pay for at least the minimum kilowatthour obligation whether or not such energy is actually taken.

6. The HECO Companies do not propose that the FIT apply to projects owned by the utility or its affiliates.